

**CALIFORNIA ENERGY COMMISSION
STAFF'S PRELIMINARY
NATURAL GAS PRICE AND
PRODUCTION FORECAST**

Assumptions and Results

In support of the
1999 NATURAL GAS PRICE FORECAST
DOCKET NO. 99-FR-1

Prepared by
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INTRODUCTION

This document explains the major assumptions and data sources underlying staff's preliminary forecast of natural gas production and wellhead prices. Since 1989, the North American Regional Gas (NARG) model has been the principal tool used by the Commission to generate production and wellhead price estimates. The NARG model is a generalized equilibrium model that simultaneously solves for supply, demand and price equilibrium for 19 North American supply and demand regions over a 45-year time horizon. California is divided into four demand regions: the Pacific Gas and Electric Company (PG&E), the Southern California Gas Company (SoCalGas), the San Diego Gas and Electric Company (SDG&E), and the enhanced oil recovery (EOR) regions. Details of the NARG model methodology, structure and operating characteristics are discussed in the **1998 Natural Gas Market Outlook**, publication number P300-98-001, available from the Commission's Publications Office and also on the Commission's Web site.

A description of NARG model enhancements and data input sources that underlie the preliminary forecast are addressed in Section I. Section II describes the resulting production and wellhead price projections for U.S. and Canadian regions, as well as an end-use price forecast by major utility service territory in California. The final section provides information about an upcoming Staff workshop to discuss the forecast and procedures for filing comments.

I. MODEL ENHANCEMENTS AND DATA INPUTS

During the past five years, staff has devoted considerable time to improving the data representing the natural gas resource base in North America. While recognizing that further enhancements in this area are still needed, staff decided to focus its attention on improving the model's ability to respond to sensitivities surrounding the power generation market. Specific details surrounding this effort begin in this section. Assumptions about initial conditions, demand projections, and other areas of interest are also described in this section.

Structural Enhancements to the NARG Model

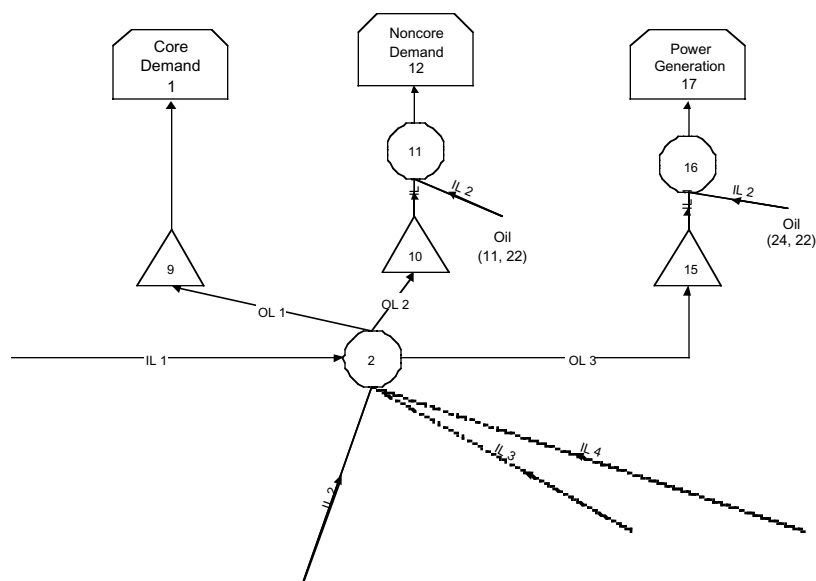
Electricity restructuring has created a myriad of opportunities for merchants to enter the power generation market once limited to regulated utilities. In California, for example, 15 merchants have 8 power plant siting cases currently under consideration with another 13 applications expected during the next 12 months. Each of these cases, as well as many proposals in other states, presume that natural gas will be the fuel of choice. Natural gas market experts, including GRI and EIA, expect

power generation to account for an additional 7 TCF of demand in North America during the next 20 years.

Recognizing the impact that the power generation market might have on any price and supply forecast, staff reconfigured each noncore demand sector in the model. In previous forecasts, staff combined the industrial and power generation subsectors to produce a single noncore sector. In this forecast, staff divided the noncore sector into industrial and power generation¹ for each of the 13 demand regions in the Lower 48. Figure 1 illustrates the new activities added to a representative demand region. Activity 15 (shaded triangle) represents the utility distribution charge assessed to electricity generators. The rate is generally less expensive than comparable rates for industrial customers. Activity 16 (shaded circle) is an allocation which allows power generation load using natural gas to compete with power generation load using fuel oil. Activity 17 (shaded tombstone) represents the total power generation load.

FIGURE 1
NEW DEMAND NODE CONFIGURATIONS IN NARG MODEL

West North Central Demand (16)



Initial Conditions

To generate a gas price forecast, the NARG model requires a set of initial conditions that balance demand and supply for the specified start or "base" year. In the present forecast, gas flows during

¹ Staff did not reconfigure the noncore sector in Canada.

1997 are input to the model as an equilibrium of balanced natural gas flows at each point in the model structure.

The California portion of the energy balance was compiled from several sources, primarily the *Quarterly Fuel and Energy Report (QFER Forms 6 and 7)*. Demand data for non-utility EOR cogeneration capacity were based on the Department of Conservation, Division of Oil and Gas publication, *83rd Annual Report of the State Oil & Gas Supervisor*. The Commission's *QFER Form 10A* provided data for California gas production transported directly to industrial and enhanced oil recovery facilities from inter- and intrastate supply sources. Submittals to the Commission under the Petroleum Industry Information Reporting Act contain data for EOR steaming and oil burn.

For the rest of the Lower 48, Staff relied heavily on EIA's *1997 Natural Gas Annual* report. The workpapers contain information on natural gas flows across state and international boundaries identified by specific pipelines. Pipeline flows were then aggregated and assigned to individual transportation links or corridors in the NARG model. To determine the proper level of base year gas production, Staff used EIA's *U.S. Crude Oil, Natural Gas and Natural Gas Liquids Reserves 1997* report and testimony provided to the Commission at a January 11, 1999 Resource Evaluation Hearing.²

The Canadian portion of the energy balance was done using several publications. *Gas Utilities - 1997*, published by Statistics Canada provided information on base year demand and gas flows between provinces. The data were converted from thousand cubic meters to billion cubic feet and split between core and noncore demand markets. Direct sales reported in the publication were allocated equally to core and noncore nodes. Provincial production estimates were obtained from *Gas Facts - 1997*, published by the American Gas Association, and discussions with CERI and NEB Staff. Oil & Gas Journal also provided valuable pieces of data via various articles throughout the past few years.

Natural Gas Demand Projections

Staff relied on a variety of sources to generate a natural gas demand forecast. California residential, commercial and industrial customer demand assumptions were based on the *1998 Baseline Energy Outlook (Publication P300-98-012)*, a Commission publication prepared by its Demand Analysis Office. The Electricity Analysis Office derived UEG and cogeneration demand estimates using electric generation capacity expansion plan results.

For all other regions in the continental United States, Staff utilized Gas Research Institute's (GRI) *Baseline Projection Data Book*, 1999 edition. Data were aggregated into core (non-switchable) and

2 Hearing held to discuss the natural gas resource assumptions for the 1999 Natural Gas Supply and Price Forecast, California Energy Commission, Docket 99-FR-1, January 11, 1999.

noncore (switchable) demand. Core demand with respect to the GRI data includes residential gas, commercial gas, 25 percent of natural gas vehicles (NGV), and 50 percent of industrial gas demand. Given that oil-on-gas competition exists in most noncore markets, noncore demand includes the remaining 50 percent of industrial gas, an increasing percentage of industrial oil (20 percent in 2002, 30 percent in 2007, 40 percent in 2012 and 50 percent thereafter), and 25 percent of commercial oil. For the power generation sector, demand projections include all power generation natural gas and oil demand.

Staff derived the Canadian natural gas demand estimate using Canadian Gas Association's ***Forecast of Domestic Natural Gas Demand:1999-2015***. Forecast data were provided by customer class for the six major Canadian provinces for the years 1997-2001, 2005, 2010, and 2015. Staff interpolated estimates for 2002, 2007, and 2012. Estimates from 2014-2019 were calculated based on the annual growth rate in demand from 2000 to 2015. Demand estimates beyond 2022 were assumed to increase at a constant one percent per year.

Staff placed 100 percent of residential and commercial requirements and 75 percent of industrial requirements for each Canadian demand region in the core sector. The remaining 25 percent of industrial demand and all electric generation requirements were allocated to noncore demand. These percentages were based on discussions with NEB representatives. Switchable fuel oil for industrial, electric generation, and petrochemical customers was also added to the noncore demand estimate, based on information obtained from communications with staff at the Canadian Energy Research Institute (CERI).

Mexican demand estimates remain the same from the previous forecast. The estimates were limited to three regions in Mexico located adjacent to the U.S. border (Baja, North, and East). Staff increased existing demand at an arbitrary one percent per year from recorded 1995 estimates. Using information provided by the EIA in its ***Natural Gas Imports and Exports*** report published in the second quarter of 1995, Staff identified new facilities expected to consume natural gas during the forecast period. Demand at these new facilities was increased at one percent per year after the project startup date. Finally, development of a Mexican natural gas market infrastructure enables Mexican production to satisfy 20 percent of requirements in the North and Eastern demand regions by 2022. Core and noncore distinctions were not addressed in this forecast.

Owner/Producer Discounts

The "Owner's Discount Rate" is defined as "the rate used by the original owner of a resource deposit to discount cash flows resulting from the sale of leases to resource producers." Conversely, the "Producer's Discount Rate" is the required rate of return on equity for all investments. Staff used a 7.5 percent producer's discount rate, a three percent owner's discount rate, and a 2.5 percent rate of debt.

Time Frame and Dollars

The present forecast uses 1997 as the base year. The NARG model generates forecast data in five-year increments starting from the 1997 base and ending with 2042. Although a 45-year forecast is generated, Staff focuses on the 2002 to 2022 forecast period. All prices in this analysis are in constant 1998 dollars. The deflator series used for this conversion was based on the February 18, 1999 inflation factors based on Gross Domestic Product, developed by the Demand Analysis Office of the Energy Commission.

II. BASECASE RESULTS

This section presents staff's preliminary forecast of natural gas production and prices by region for North America over the 20-year forecast horizon (2002-2022). Wellhead prices and production levels by major producing region are addressed followed by the natural gas supplies and prices at the California border. The section concludes with a discussion of the assumptions used in generating the end-use price forecast for each market sector in the state.

A. Wellhead Prices and Production

In the Lower 48, natural gas production is expected to grow from a recorded 18.5 TCF in 1997 to 19.6 TCF in 2002, the first forecast year (Table 1). Between 2002 and 2022, Lower 48 production is expected to grow by 1.8 percent per year, reaching 28.2 TCF by the end of the forecast period. While also exhibiting positive growth, Canadian production will grow at a slower pace (1.2 percent per year through the year 2022) compared to the percentage increase projected for the Lower 48.

Regional breakdowns of production are also provided in Table 1. Natural gas produced in the Gulf Coast region will continue to account for the largest share of Lower 48 production during the 2002-2022 forecast period. Recognizing strong resource potential in the region, Rocky Mountain production is expected to emerge as the second largest source of natural gas in the Lower 48, surpassing production from the Permian region in 2002 and Anadarko region by the year 2012. Staff anticipates the strong growth in production in the Rocky Mountains to be driven by conventional production in the Wyoming Thrust Belt and tight sands production in the Greater Green River Basin.

In Canada, Alberta producers will continue to provide the bulk of Canadian production even though strong growth on a percentage basis will be the case for British Columbia producers. Canadian production for all regions shall increase by 3 TCF from 1997 to 2022. Canadian exports are expected to grow steadily through the forecast period, driven by the recent expansion of Northern Border Pipeline, the completion of the Maritimes and Northeast Pipeline from Nova Scotia towards the end of this year, and the startup of the Alliance Pipeline project from Alberta to the Midwest in 2001. Exports to the United States are expected to grow from 2.9 TCF in the 1997 base year to 4.2 TCF by the end of the forecast period.

Table 2 compares natural gas prices by region and in the aggregate. For the Lower 48, the average price increases from \$1.86 per MCF in 2002 to \$2.52 per MCF in 2022, an increase of 1.5 percent per year (in 1998 dollars) on an average annual basis. The least expensive producing region remains the Northern Great Plains while the Appalachian region is the highest. Canadian wellhead prices escalate 1.9 percent per year, from \$1.52 per MCF in 2002 to \$2.20 per MCF in 2022.

<p>TABLE 1 LOWER 48 AND CANADIAN PRODUCTION (TCF PER YEAR) 1999 Preliminary Base Case</p>						
Producing Region	1997	2002	2007	2012	2017	2022
LOWER 48						
Anadarko	2.308	2.449	2.392	2.331	2.407	2.226
Appalachia	0.529	0.829	1.004	1.304	1.590	1.838
California	0.297	0.297	0.356	0.361	0.390	0.422
Gulf Coast	10.449	9.369	9.869	11.116	12.322	13.334
North Central	0.258	0.581	0.650	0.737	0.809	0.870
Northern Great Plains	0.200	0.331	0.371	0.427	0.474	0.520
Pacific Northwest	0.001	0.018	0.039	0.069	0.118	0.183
Permian	1.668	1.721	1.722	1.830	1.794	1.751
Rocky Mountains	1.230	1.939	2.345	2.682	3.221	4.061
San Juan	1.403	1.901	2.033	2.103	2.077	1.983
Total: Lower 48	18.343	19.426	20.779	22.958	25.201	27.188
CANADA						
Alberta	4.495	5.410	5.977	6.556	6.932	7.159
British Columbia	0.711	0.976	1.037	0.983	0.987	1.012
Eastern Canada	0.000	0.012	0.093	0.120	0.146	0.168
Saskatchewan	0.224	0.256	0.150	0.140	0.113	0.113
Total: Canada	5.430	6.654	7.257	7.799	8.178	8.452

<p>TABLE 2 LOWER 48 AND CANADIAN WELLHEAD PRICES (1998\$ PER MCF) 1999 Preliminary Base Case</p>					
Producing Region	2002	2007	2012	2017	2022
LOWER 48					
Anadarko	1.93	2.14	2.39	2.59	2.82
Appalachia	2.41	2.56	2.73	2.86	2.97
California	2.18	2.36	2.56	2.78	3.01
Gulf Coast	1.86	2.03	2.23	2.43	2.58
North Central	2.01	2.08	2.16	2.24	2.31
Northern Great Plains	1.66	1.72	1.78	1.85	1.91
Pacific Northwest	2.22	2.39	2.54	2.64	2.72
Permian	1.82	2.00	2.23	2.42	2.62
Rocky Mountains	1.69	1.74	1.82	1.93	2.04
San Juan	1.63	1.78	1.93	2.15	2.36
Total: Lower 48	1.86	2.01	2.19	2.37	2.52
CANADA					
Alberta	1.48	1.62	1.77	1.95	2.13
British Columbia	1.63	1.83	2.06	2.25	2.43
Eastern Canada	N/A	2.87	2.59	2.80	3.02
Saskatchewan	2.00	2.29	2.57	2.91	3.18
Total: Canada	1.52	1.68	1.83	2.01	2.20

B. Natural Gas Supplies and Prices at the California Border

Natural gas produced in the Southwest is expected to remain the principal source of supply for California consumers during the next 20 years, accounting for approximately 45 percent of total statewide requirements. Supplies from the Southwest increase from 0.9 TCF in the 1997 base year, at an annual growth rate of about 1 percent, to almost 1.6 TCF in 2022. Much of this increase can be attributed to new demand in the Baja region of Northern Mexico, which will have its gas delivered through California.

The Rocky Mountain region continues to be a fast growing supply area, increasing by nearly 2 percent per year. Flows from the Rocky Mountain region to California increase from 0.23 TCF in 1997 to 0.38 TCF by 2022. Remaining statewide natural gas requirements will be met by Canadian, and in-state producers. Canadian deliveries to California will satisfy about one-quarter of total demand, with California production providing the remainder.

Regarding estimates of border prices at Malin, Topock, or Wheeler Ridge, Staff expects prices to increase 1.7 percent per year from \$2.02 per MCF in 2002 to \$2.86 per MCF in the year 2022 (prices expressed in constant 1998 dollars). Specific estimates of supplies and prices available to California by region appear in Table 3.

TABLE 3 CALIFORNIA BORDER SUPPLY AVAILABILITY AND PRICE 1999 Preliminary Base Case						
Producing Region	1997	2002	2007	2012	2017	2022
Production (TCF):						
California	0.297	0.292	0.358	0.363	0.383	0.401
Southwest	0.885	1.016	1.131	1.159	1.150	1.157
Rocky Mountains	0.232	0.272	0.319	0.341	0.360	0.380
Canada	0.599	0.528	0.573	0.617	0.678	0.731
Total Supply Available to California	2.012	2.108	2.381	2.480	2.570	2.669
Price (1998\$/MCF)						
California	N/A	2.13	2.30	2.50	2.70	2.91
Southwest	N/A	2.02	2.25	2.45	2.68	2.91
Rocky Mountains	N/A	2.10	2.32	2.52	2.74	2.96
Canada	N/A	1.96	2.13	2.30	2.50	2.71
Average Price at California Border	N/A	2.02	2.23	2.42	2.64	2.86

C. End-Use Price Forecast

This section describes the Energy Commission's end-use natural gas price forecast by sector for the Pacific Gas and Electric Company (PG&E), Southern California Gas Company (SoCalGas) and San Diego Gas and Electric Company (SDG&E) service areas. The forecast covers a twenty-year horizon through the year 2019 and uses the California border prices described in the

previous section as a starting point. Those prices are then coupled with the results of staff's in-state transmission and distribution projections to generate the end-use price forecast.

1. Assumptions

Most of the basic procedures and assumptions used to prepare the 1998 natural gas supply and price forecast were used in this analysis.³ Modifications to the assumptions in the utility transmission/distribution pricing analysis included the following:

- Natural Gas Supply Pool Assumptions. The California border prices discussed in the previous section were assumed to vary by customer class depending on the supply and capacity mix assumed. In previous forecasts, staff computed separate border prices for the core, noncore and electricity customers. This forecast combines the border price for the noncore (industrial) and electricity generation customers into one pool. This change was made since the utilities have sold their fossil-fuel powered generation facilities and remaining firm interstate transportation commitments are no longer applicable to electric generation customer class.
- Natural Gas Demand for Electricity Generation. The demand for natural gas for electricity generation in this forecast uses results from the *1996 Electricity Report* (ER-96) analysis as a starting point. Staff applied a simple adjustment to the ER-96 gas demand to be consistent with the demand projections described in the *1998 Baseline Energy Outlook*.⁴ The two forecasts were compared for each year and the percentage change between a given year's electricity demand was used to adjust the corresponding gas demand for that same period. For instance, if the 1998 electricity demand in a specific service area was three percent higher than the ER-96 demand, the corresponding natural gas demand was also assumed to increase by three percent.
- Natural Gas Utility Margin Requirements. Staff assumed the CPUC would adopt performance-based rate procedures for determining margin requirements for each of the natural gas utilities. The procedures used are consistent with those applicable to SoCalGas, adopted in CPUC Decision 97-07-054. The margin required was calculated using the following formula:

$$\text{Margin (Year 1)} = \text{Margin (Year 0)} * \{1 + \text{Inflation} + \text{Productivity} + \text{Growth in Throughput}\}$$

³ California Energy Commission, *1998 Natural Gas Market Outlook, Staff Report*, P300-98-006, June 1998.

⁴ California Energy Commission, *1998 Baseline Energy Outlook*, P300-98-012, August 1998.

The formula varies slightly from the actual formula in the CPUC decision: staff uses total demand growth while the decision places greater emphasis on customer specific margins. In using the formula, staff incorporated its February 18, 1999 inflation factors, a 1.5 percent production factor for all years, and a demand growth rate based on staff's demand forecast. Base year 1999 margin requirements were obtained from tariffs effective in January 1999 for each service area. SDG&E transmission payments to SoCalGas were removed from the SoCalGas margin forecast and were accounted for separately.

In the absence of new CPUC cost allocation decisions, base year factors to allocate margin to the rate classes remained basically unchanged from the 1998 price forecast. Allocation factors for future years were modified to reflect the change in the Staff's natural gas demand forecast for power generation.

2. End-Use Price Summaries

Table 4 summarizes the annual growth rates of end-use natural gas prices by utility service area, for each market sector. Tables 5-7 provide the results of the Preliminary Base Case forecast by end-use sector for each natural gas utility. The sector price forecast begins with year 1999, except for the PG&E service area, for which staff estimated the same for the year 1999.

<p style="text-align: center;">TABLE 4 REAL DOLLAR NATURAL GAS PRICE GROWTH RATE BY SECTOR AND UTILITY SERVICE AREA 1998 —2019 (annual percent)</p>				
Natural Gas Utility Service Area	Core Residential, Commercial	Noncore Industrial	Electricity Generation	System Average
PG&E	-0.4	0.7	0.8	-0.2
SoCal Gas	-0.7	0.5	0.3	-0.7
SDG&E	-0.5	1.3	1.0	0.2

In real terms the price forecast is fairly flat. While commodity prices increase over time, the distribution costs drop for all sectors over time, resulting in a fairly flat price projection. For the core sector (consisting of residential, commercial and small industrial customers), the distribution costs drop at a faster rate than the increase in commodity costs. As a result, so over the study period, core prices decrease slightly in real terms. On the other hand, commodity prices rise faster than the drop in distribution costs for noncore (industrial) customers. This provides a slight growth in noncore prices over the forecast horizon.

Table 5									
PG&E									
Sept 1999 Base Case Price Forecast									
End-use Natural Gas Price Forecast by Sector									
1998 Dollars per mcf									
	Core				Noncore				System Average
Year	Res	Comm	Indust		Comm	Indust	TEOR	Cogen	
1990	6.73	6.64	5.87		3.80	4.13	3.08	3.82	4.89
1991	6.76	6.75	5.91		3.14	3.29	3.64	3.30	4.58
1992	6.50	7.10	5.29		3.04	2.43	2.86	3.01	4.14
1993	6.15	6.58	5.21		3.26	2.41	2.56	3.25	4.29
1994	6.40	6.62	5.10		3.16	2.15	2.14	2.43	3.87
1995	6.67	6.73	4.90		2.65	1.94	1.60	2.36	4.00
1996	6.02	6.01	4.94		3.41	2.42	2.10	2.48	4.04
1997	6.21	6.22	5.31		2.89	2.83	3.12	2.81	4.21
1998	6.91	7.54	4.44		3.76	2.73	2.65	2.63	4.24
1999	6.87	6.86	3.99		3.76	2.73	2.66	2.66	4.06
2000	6.61	6.60	3.89		3.58	2.57	2.51	2.49	3.81
2001	6.46	6.44	3.86		3.56	2.55	2.50	2.48	3.75
2002	6.29	6.28	3.83		3.51	2.49	2.46	2.43	3.65
2003	6.33	6.32	3.87		3.56	2.54	2.51	2.47	3.68
2004	6.30	6.29	3.88		3.57	2.57	2.54	2.50	3.70
2005	6.37	6.36	3.93		3.62	2.61	2.59	2.54	3.73
2006	6.27	6.26	3.91		3.63	2.65	2.62	2.58	3.69
2007	6.32	6.31	3.95		3.67	2.68	2.66	2.62	3.74
2008	6.30	6.29	3.96		3.69	2.72	2.70	2.65	3.74
2009	6.31	6.30	3.98		3.73	2.75	2.74	2.68	3.75
2010	6.31	6.30	4.00		3.74	2.78	2.77	2.71	3.77
2011	6.29	6.28	4.02		3.77	2.82	2.80	2.75	3.79
2012	6.31	6.31	4.05		3.81	2.86	2.84	2.79	3.81
2013	6.32	6.32	4.08		3.84	2.90	2.89	2.84	3.86
2014	6.37	6.36	4.12		3.90	2.95	2.94	2.89	3.90
2015	6.36	6.36	4.15		3.93	3.00	2.98	2.93	3.92
2016	6.37	6.37	4.18		3.97	3.04	3.02	2.98	3.96
2017	6.37	6.37	4.21		4.01	3.09	3.07	3.03	3.99
2018	6.38	6.38	4.24		4.05	3.14	3.12	3.07	4.03
2019	6.41	6.41	4.27		4.09	3.19	3.16	3.12	4.07
Note: * 1990 - 1997 prices are historical for residential, commercial, industrial, and TEOR;									
from QFER Form 7.									
* 1990 - 1998 prices are historical for cogeneration and EG.									
* Later years are forecasted.									
01-Nov-99									

Table 6									
SoCal Gas									
Sept 1999 Base Case Price Forecast									
End-use Natural Gas Price Forecast by Sector									
1998 Dollars per mcf									
	Core			Noncore					System
Year	Res	Comm	Indust	Comm	Indust	TEOR	Cogen	EG	Average
1990	6.71	7.10	6.28	4.48	3.98	3.54	3.85	3.85	4.75
1991	7.33	7.70	7.70	4.10	3.82	3.00	3.38	3.38	4.72
1992	7.56	8.00	7.21	5.64	4.23	3.18	3.29	3.29	5.21
1993	7.36	7.84	7.14	5.22	3.91	3.31	3.30	3.30	5.18
1994	7.25	7.54	7.01	3.48	3.08	2.60	2.77	2.77	4.90
1995	7.52	7.42	6.56	2.51	2.40	2.10	2.37	2.37	4.71
1996	7.08	6.46	5.54	2.95	2.80	2.56	3.09	3.09	4.78
1997	7.38	6.70	5.63	3.11	3.45	3.01	3.36	3.36	4.94
1998	7.34	6.00	5.05	2.95	3.06	2.92	2.96	2.96	4.82
1999	6.50	4.72	3.77	2.93	2.93	2.84	2.68	2.68	4.09
2000	6.29	4.54	3.61	2.72	2.72	2.81	2.45	2.45	3.86
2001	6.23	4.50	3.57	2.69	2.69	2.78	2.42	2.42	3.81
2002	6.12	4.42	3.52	2.66	2.66	2.76	2.39	2.39	3.73
2003	6.17	4.47	3.57	2.72	2.71	2.81	2.45	2.45	3.79
2004	6.08	4.44	3.57	2.76	2.75	2.85	2.50	2.50	3.75
2005	6.16	4.51	3.64	2.81	2.80	2.91	2.55	2.55	3.83
2006	6.06	4.48	3.64	2.84	2.84	2.94	2.59	2.59	3.81
2007	6.06	4.47	3.67	2.87	2.86	2.97	2.62	2.62	3.83
2008	6.05	4.50	3.71	2.89	2.89	2.99	2.65	2.65	3.83
2009	6.15	4.65	3.79	2.93	2.93	3.03	2.69	2.69	3.88
2010	6.14	4.66	3.82	2.97	2.96	3.07	2.73	2.73	3.91
2011	6.12	4.66	3.84	3.01	3.00	3.11	2.77	2.77	3.91
2012	6.16	4.70	3.89	3.05	3.04	3.15	2.81	2.81	3.95
2013	6.16	4.72	3.94	3.10	3.09	3.20	2.87	2.87	3.97
2014	6.21	4.77	3.99	3.15	3.15	3.25	2.92	2.92	4.02
2015	6.22	4.80	4.02	3.20	3.20	3.30	2.97	2.97	4.05
2016	6.24	4.83	4.06	3.25	3.25	3.35	3.03	3.03	4.09
2017	6.26	4.86	4.10	3.30	3.30	3.40	3.08	3.08	4.12
2018	6.28	4.90	4.16	3.35	3.35	3.45	3.13	3.13	4.16
2019	6.32	4.95	4.21	3.41	3.40	3.50	3.18	3.18	4.20
Note: * 1990 - 1998 prices are historical for residential, commercial, industrial, and TEOR;									
Obtained from QFER 7.									
* 1990 - 1998 prices are historical for cogeneration and UEG.									
* 1998 and later years are forecasted.									
01-Nov-99									

Table 7										
SDG&E										
Sept 1999 Base Case Price Forecast										
End-use Natural Gas Price Forecast by Sector										
1998 Dollars per mcf										
	Core				Noncore				System	
Year	Res	Comm	Indust		Comm	Indust	TEOR	Cogen	EG	Average
1990	6.74	6.71	6.39		4.63	4.63	0.00	3.89	3.89	5.06
1991	6.35	6.44	6.41		4.07	4.07	0.00	3.41	3.41	4.61
1992	6.77	6.99	7.08		4.22	4.22	0.00	3.36	3.36	4.94
1993	7.18	6.76	7.05		2.70	2.61	0.00	3.49	3.49	5.10
1994	7.22	5.79	6.33		3.77	4.08	0.00	3.19	3.19	5.00
1995	6.76	5.58	6.26		2.84	2.87	0.00	2.28	2.28	4.13
1996	6.83	5.91	6.70		3.29	2.94	0.00	2.66	2.66	4.56
1997	7.53	6.93	7.84		3.40	3.40	0.00	3.07	3.07	4.74
1998	7.37	6.28	7.28		2.79	2.79	0.00	2.78	2.78	4.40
1999	6.17	5.55	4.30		3.05	3.05	0.00	2.86	2.86	4.01
2000	5.85	5.27	4.11		2.91	2.91	0.00	2.73	2.73	3.80
2001	5.89	5.30	4.12		2.89	2.89	0.00	2.71	2.71	3.87
2002	5.84	5.26	4.08		2.85	2.85	0.00	2.68	2.68	3.86
2003	6.50	5.84	4.45		3.00	3.00	0.00	2.79	2.79	4.25
2004	6.26	5.63	4.35		3.00	3.00	0.00	2.81	2.81	4.13
2005	6.40	5.76	4.44		3.06	3.06	0.00	2.86	2.86	4.25
2006	6.25	5.63	4.38		3.07	3.07	0.00	2.89	2.89	4.16
2007	6.35	5.72	4.45		3.12	3.12	0.00	2.93	2.93	4.18
2008	6.41	5.78	4.50		3.16	3.16	0.00	2.96	2.96	4.21
2009	6.50	5.87	4.57		3.21	3.21	0.00	3.00	3.00	4.32
2010	6.34	5.73	4.50		3.21	3.21	0.00	3.02	3.02	4.26
2011	6.30	5.70	4.50		3.24	3.24	0.00	3.06	3.06	4.23
2012	6.41	5.80	4.58		3.30	3.30	0.00	3.10	3.10	4.31
2013	6.41	5.81	4.60		3.34	3.34	0.00	3.15	3.15	4.33
2014	6.48	5.87	4.66		3.40	3.40	0.00	3.21	3.21	4.38
2015	6.51	5.91	4.71		3.45	3.45	0.00	3.26	3.26	4.44
2016	6.48	5.89	4.71		3.49	3.49	0.00	3.30	3.30	4.45
2017	6.50	5.91	4.75		3.53	3.53	0.00	3.35	3.35	4.48
2018	6.53	5.95	4.79		3.58	3.58	0.00	3.40	3.40	4.53
2019	6.58	6.00	4.84		3.64	3.64	0.00	3.45	3.45	4.58
Note: * 1990 - 1998 prices are historical for residential, commercial, industrial, and TEOR										
	Obtained from QFER Form 7.									
* 1990 — 1998 prices are historical prices for cogeneration and UEG										
* 1999 and later prices are forecasted.										
01-Nov-99										

3. Natural Gas Prices for the Electricity Generation Sector:

Figures 2 to 4 compare the current preliminary forecast with the past two adopted forecasts (adopted in the 1995 and the 1998 natural gas price forecasts) for PG&E, SoCalGas and SDG&E service areas, respectively. Figure 5 compares the current forecasts for the three service areas. The detailed forecast for natural gas demand for electricity generation, consisting of the commodity, transportation and total price forecast (in constant 1998 \$/MCF) and in nominal dollars per million btu (\$/MMBtu)) for each of the natural gas services areas. These figures and tables indicate that natural gas for generation will be very competitive in the service areas.

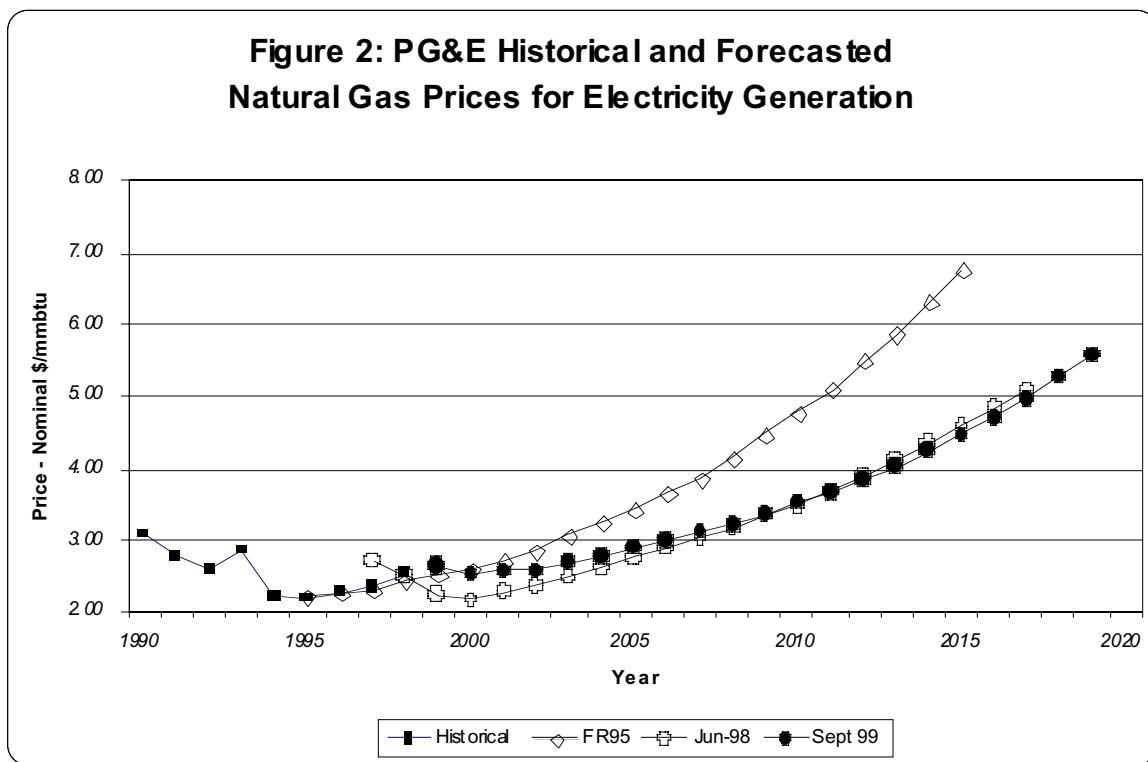


Figure 3: SoCalGas Historical and Forecasted Natural Gas Prices for Electricity Generation

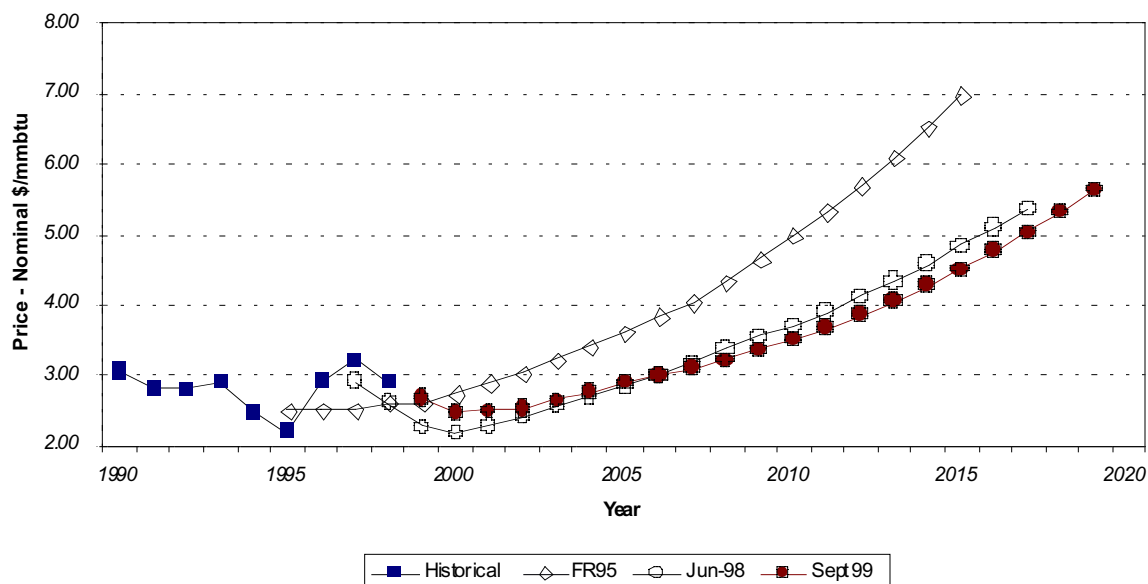
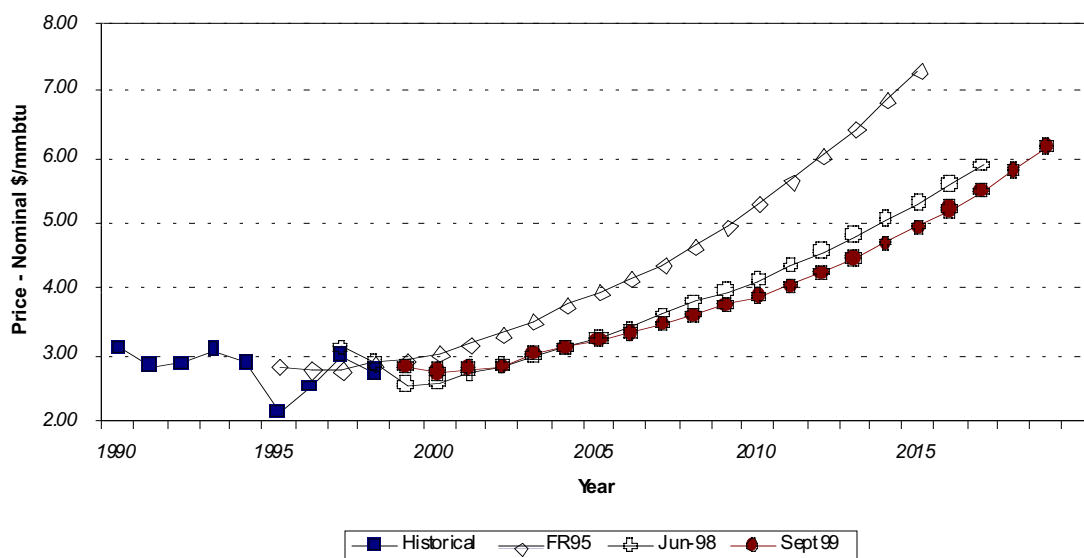


Figure 4: SDG&E Historical and Forecasted Natural Gas Prices for Electricity Generation



As seen in Figures 2 to 4, the preliminary forecasts (nominal prices in \$/MMBtu) are slightly higher in the near term and lower in the long term than the June 1998 forecast. The preliminary forecasts also indicate a fairly flat nominal natural gas price trend for electricity generation customers in both the PG&E and SDG&E service areas for the next five years.

Figures 3 and 5 show that, in the SoCalGas service area, nominal prices drop by \$0.41 per MMBtu compared to the historical 1998 price. The decline is slightly less than the drop that occurs in the PG&E service area. Much of the decline can be attributed to a reallocation of utility distribution costs. In the longer term, SoCalGas prices rise to match PG&E. SDG&E power generation gas prices remain a nominal \$0.30 to \$0.45 per MMBtu higher than the other service area prices. This forecast assumes that the CPUC continues its current policy of passing SoCalGas in-state transport costs through to SDG&E. In the ongoing utility rate case proceedings, many parties have argued for the same electricity generation natural gas rates for SoCalGas and SDG&E service areas. The final results of these proceedings could have an impact on the direction of this forecast. Tabular results for each service area are provided in Tables 8-10.

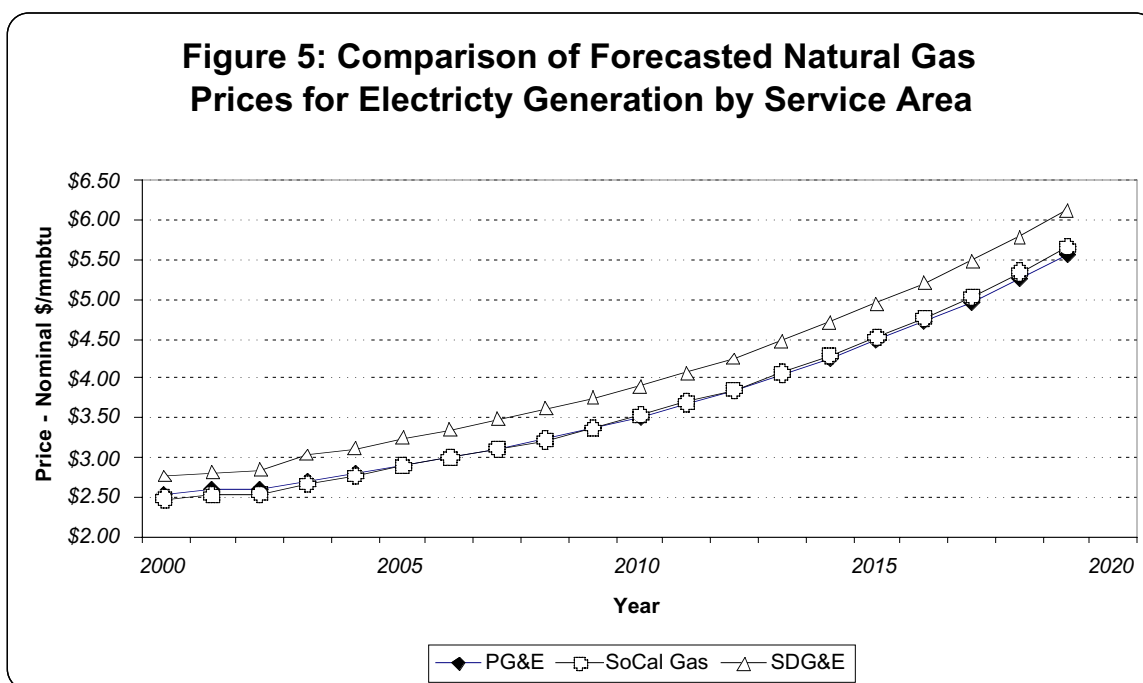


Table 8									
PG&E Service Area									
Sept 1999 Base Case Price Forecast									
Electricity Generation Gas Price Forecast									
1998 \$ per mmBtu					Nominal \$ per mmbtu				
		Transportation		Total			Transportation		Total EG
Year	Commodity	Interstate	Intrastate	Price	Year	Commodity	Interstate	Intrastate	Price
1990				3.72	1990				3.09
1991				3.24	1991				2.79
1992				2.94	1992				2.61
1993				3.17	1993				2.88
1994				2.36	1994				2.20
1995				2.32	1995				2.21
1996				2.44	1996				2.37
1997				2.73	1997				2.70
1998				2.57	1998				2.57
1999	1.75	0.28	0.58	2.60	1999	1.78	0.29	0.59	2.65
2000	1.74	0.28	0.43	2.45	2000	1.80	0.29	0.45	2.54
2001	1.70	0.31	0.42	2.43	2001	1.81	0.33	0.44	2.58
2002	1.66	0.31	0.41	2.38	2002	1.81	0.33	0.44	2.58
2003	1.70	0.31	0.41	2.42	2003	1.88	0.35	0.45	2.69
2004	1.73	0.33	0.40	2.45	2004	1.97	0.37	0.45	2.79
2005	1.76	0.34	0.40	2.49	2005	2.04	0.39	0.46	2.89
2006	1.79	0.35	0.39	2.53	2006	2.12	0.41	0.46	3.00
2007	1.82	0.36	0.38	2.56	2007	2.21	0.44	0.47	3.12
2008	1.85	0.37	0.38	2.60	2008	2.31	0.46	0.47	3.24
2009	1.88	0.38	0.37	2.63	2009	2.41	0.49	0.48	3.38
2010	1.91	0.39	0.36	2.66	2010	2.52	0.51	0.48	3.52
2011	1.94	0.40	0.36	2.70	2011	2.64	0.54	0.49	3.68
2012	1.97	0.41	0.36	2.74	2012	2.77	0.57	0.51	3.85
2013	2.01	0.41	0.36	2.78	2013	2.92	0.60	0.52	4.04
2014	2.05	0.42	0.36	2.83	2014	3.08	0.63	0.54	4.25
2015	2.09	0.43	0.36	2.87	2015	3.25	0.66	0.56	4.47
2016	2.13	0.43	0.36	2.92	2016	3.44	0.70	0.57	4.71
2017	2.17	0.44	0.35	2.97	2017	3.64	0.74	0.59	4.98
2018	2.21	0.45	0.35	3.01	2018	3.86	0.79	0.62	5.26
2019	2.25	0.46	0.35	3.06	2019	4.09	0.84	0.64	5.58
Notes: 1990 — 1998 total prices are historical, taken from PG&E's UMFOR.									
* All Forecasted costs are assumed to be variable.									
* Commodity price = California Border price less interstate transport cost.									
* Assumed 1020 btu per cf for forecasted prices.									
* Inflation based on 1998=100 using Feb. 18, 1999 deflators.									
* Based on Sept. 1999 EG natural gas demand forecast.									
* May not sum due to rounding.									
01-Nov-99									

Table 9									
SoCalGas Service Area									
Sept 1999 Base Case Price Forecast									
Electricity Generation Gas Price Forecast									
1998 \$ per mmBtu					Nominal \$ per mmbtu				
		Transportation		Total			Transportation		total EG
Year	Commodity	Interstate	Intrastate	Price	Year	Commodity	Interstate	Intrastate	Price
1990				3.68	1990				3.05
1991				3.26	1991				2.81
1992				3.14	1992				2.79
1993				3.17	1993				2.88
1994				2.67	1994				2.49
1995				2.30	1995				2.20
1996				3.00	1996				2.91
1997				3.26	1997				3.23
1998				2.89	1998				2.89
1999	1.85	0.30	0.46	2.61	1999	1.89	0.30	0.47	2.66
2000	1.84	0.28	0.26	2.39	2000	1.91	0.29	0.27	2.48
2001	1.83	0.28	0.26	2.36	2001	1.94	0.29	0.27	2.51
2002	1.80	0.28	0.25	2.33	2002	1.96	0.30	0.27	2.53
2003	1.84	0.30	0.25	2.39	2003	2.04	0.34	0.28	2.65
2004	1.87	0.33	0.24	2.43	2004	2.13	0.38	0.27	2.77
2005	1.90	0.35	0.24	2.49	2005	2.20	0.40	0.27	2.88
2006	1.94	0.36	0.22	2.53	2006	2.30	0.43	0.27	3.00
2007	1.97	0.37	0.22	2.56	2007	2.39	0.45	0.27	3.11
2008	2.00	0.36	0.22	2.58	2008	2.50	0.46	0.27	3.22
2009	2.04	0.37	0.21	2.62	2009	2.61	0.48	0.27	3.37
2010	2.07	0.38	0.21	2.66	2010	2.73	0.50	0.28	3.52
2011	2.10	0.39	0.21	2.70	2011	2.87	0.53	0.29	3.68
2012	2.14	0.40	0.21	2.75	2012	3.01	0.56	0.29	3.86
2013	2.18	0.41	0.21	2.80	2013	3.17	0.59	0.30	4.06
2014	2.23	0.41	0.21	2.85	2014	3.35	0.62	0.31	4.28
2015	2.28	0.42	0.20	2.90	2015	3.54	0.65	0.32	4.52
2016	2.32	0.43	0.20	2.95	2016	3.75	0.69	0.33	4.77
2017	2.37	0.43	0.20	3.00	2017	3.97	0.73	0.34	5.04
2018	2.41	0.44	0.20	3.05	2018	4.22	0.77	0.35	5.33
2019	2.46	0.45	0.20	3.11	2019	4.48	0.81	0.36	5.66
Notes: 1990 - 1998 total price are historical taken from SCE's UMFOR.									
All forecasted costs are assumed to be variable.									
Commodity price = California Border price less interstate pipeline demand charges.									
Assumed 1025 btu per cf for forecasted prices.									
Inflation based on 1998=100 using Feb. 18, 1999 deflators.									
Based on Sept. 1999 EG natural gas demand forecast.									
May not sum due to rounding.									

Table 10									
SDG&E Service Area									
Sept 1999 Base Case Price Forecast									
Electricity Generation Gas Price Forecast									
1998 \$ per mmBtu					Nominal \$ per mmBtu				
		Transportation		Total			Transportation		Total EG
Year	Commodity	Interstate	Intrastate	Price	Year	Commodity	Interstate	Intrastate	Price
1990				3.78	1990				3.13
1991				3.32	1991				2.86
1992				3.26	1992				2.88
1993				3.40	1993				3.09
1994				3.12	1994				2.90
1995				2.24	1995				2.14
1996				2.63	1996				2.55
1997				3.03	1997				3.03
1998				2.75	1998				2.75
1999	1.81	0.37	0.61	2.79	1999	1.84	0.38	0.62	2.84
2000	1.80	0.36	0.51	2.66	2000	1.87	0.37	0.53	2.77
2001	1.78	0.35	0.51	2.64	2001	1.89	0.37	0.54	2.80
2002	1.76	0.35	0.50	2.61	2002	1.91	0.38	0.54	2.84
2003	1.79	0.37	0.56	2.72	2003	1.99	0.41	0.62	3.02
2004	1.82	0.39	0.53	2.74	2004	2.08	0.44	0.60	3.12
2005	1.86	0.40	0.53	2.79	2005	2.15	0.47	0.62	3.23
2006	1.90	0.41	0.51	2.82	2006	2.25	0.48	0.61	3.34
2007	1.93	0.41	0.52	2.86	2007	2.34	0.50	0.63	3.48
2008	1.96	0.40	0.53	2.89	2008	2.45	0.50	0.66	3.61
2009	1.99	0.41	0.53	2.93	2009	2.56	0.52	0.67	3.76
2010	2.03	0.41	0.51	2.95	2010	2.68	0.54	0.67	3.89
2011	2.06	0.42	0.50	2.98	2011	2.81	0.57	0.68	4.06
2012	2.10	0.43	0.50	3.03	2012	2.95	0.60	0.71	4.26
2013	2.14	0.43	0.50	3.08	2013	3.12	0.63	0.73	4.47
2014	2.19	0.44	0.50	3.13	2014	3.29	0.66	0.75	4.70
2015	2.24	0.44	0.50	3.18	2015	3.48	0.69	0.77	4.95
2016	2.28	0.45	0.49	3.22	2016	3.69	0.72	0.79	5.20
2017	2.33	0.45	0.48	3.27	2017	3.91	0.76	0.81	5.48
2018	2.37	0.46	0.48	3.32	2018	4.15	0.80	0.84	5.79
2019	2.42	0.46	0.48	3.37	2019	4.41	0.84	0.88	6.13
Note: * 1990 — 1996 total prices are historical, obtained from UMFOR.									
* All Forecasted costs are assumed to be variable.									
* Commodity price = California Border price less interstate pipeline demand charges.									
* Assumed 1025 btu per cf for forecasted prices.									
* Inflation based on 1998=100 using Feb. 19, 1999 deflators.									
* Based on Sept. 1999 EG gas demand forecast									
* May not sum due to rounding.									
01-Nov-99									

III. NEXT STEPS

The Commission will hold a hearing on November 22, 1999 to discuss the natural gas price and supply forecast described in this report. The meeting will be held in Hearing Room A at the California Energy Commission in Sacramento. In preparation for that meeting, Staff is requesting comments or suggestions about the forecast from interested parties.

Your comments will be accepted either orally or in writing. Please contact the following people if you have any comments or questions about the forecast:

Jairam Gopal	(916) 654-4880	jgopal@energy.state.ca.us
Bill Wood	(916) 654-4882	bwood@energy.state.ca.us

If you wish to mail your comments, please do so to either of the above people by November 19 at the following address:

California Energy Commission
Fuel Resources Office
1516 Ninth Street, MS-23
Sacramento, CA 95814